COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF TELECOMMUNICATIONS AND ENERGY

RESPONSE OF BAY STATE GAS COMPANY TO THE
SECOND SET OF INFORMATION REQUESTS FROM THE ATTORNEY GENERAL
D. T. E. 05-27

Date: June 6, 2005

Responsible: Danny G. Cote, General Manager

AG-2-27 Produce copies of all decisions and orders of the New Hampshire Public Utility Commission related to Northern Utilities problem with accelerated bare steel corrosion leaks. State whether the Northern Utilities program included the replacement of coated steel without cathodic protection.

Response: Please see Attachment AG-2-27. The program was focused on bare steel, saving for a later date the replacement of unprotected coated steel.

DR 91-081

NORTHERN UTILITIES, INC.

Report and Order Approving the Settlement
Agreement for the 1992 Step Adjustment

Appearances: LeBoeuf, Lamb, Leiby & MacRae by Paul K. Connolly, Jr., Esq. and Scott J. Mueller, Esq. on behalf of Northern Utilities, Inc.; and for the Public Utilities Commission, Eugene F. Sullivan, III, Esq.

REPORT

I. Procedural History

On July 21, 1992, the commission issued its Order No. 20,546 approving the Settlement Agreement on permanent rates for Northern. Article III of that Settlement Agreement provided for the implementation of step adjustments in base rates to be effective for meter readings on or after November 1, 1992, and annually thereafter until the agreed bare steel replacement program is completed. Based on a review by the PUC Gas Safety Engineer, there definitely was a serious safety problem on the Company's bare steel distribution system. The Safety Engineer suggested to the Company that a two-phase program be implemented: the first phase would schedule replacement of areas that required immediate repair, the second phase would schedule replacement of areas that did not pose any immediate risk to safety. On September 21, 1992, Northern filed revised tariff pages and a petition with the commission seeking authorization for the initial step adjustment in the amount of $624,907. The staff conducted an audit at the company's headquarters in Westborough, Massachusetts between September 8, 1992 and September 25, 1992 with respect to Northern's proposed step adjustment including a field visit to Northern's offices in Portsmouth, NH. On October 12, 1992 staff returned to Westborough, Massachusetts to complete its review, specifically its review of actual charges for the month of September, 1992. Following extensive discussions the staff and Northern reached agreement on the issues in this proceeding. On October 14, 1992, a hearing was held regarding the company's proposed Step adjustment. At the hearing, the company submitted testimony of Richard P. Cencini, Director of Regulatory Affairs, addressing the Settlement Agreement entered into by the staff and the company.

II. Overall Settlement Agreement

The company's original petition and exhibits proposed a Step Adjustment in the amount of $624,907. Based on a review of the Company's books and records and extensive discussions on the issues involved, the parties agreed to a Step Adjustment in the amount of $501,450. Both staff and the Company agree that this amount is just and reasonable.

III. Components of the Settlement Agreement

Return and Related Income Taxes on Non-Revenue Producing Investments

The return and related income taxes on Northern's investment for the period April 1, 1991 through September 30, 1992 is shown on Attachment A, Exhibit 1, as revised on October

12, 1992 ($681,278). The amount of the step adjustment has been calculated using the actual capital expenditures for the above stated period adjusted as a result of the staff audit and the pre-tax rate of return of 13.19 percent and reflecting cost of service principles including the treatment of the deferred tax reserve. Staff believes that this amount is appropriate.

Annualized Depreciation Expense

Annualized depreciation expense for investments other than services is based on Northern's actual plant additions mentioned above and the depreciation rates included in the Settlement Agreement on permanent rates. Annualized depreciation expense for replacement services is based on actual plant additions mentioned above and the depreciation rate of 3.14 percent included in the Settlement Agreement on the Step Adjustment (see below). The parties agree that the expense which results from the use of the 3.14 percent depreciation rate is fair and reasonable. These expenses are summarized on Attachment A, Exhibit 1 as revised on October 12, 1992 ($183,875).

Proformed Test Year Expense For Depreciation

The amount of proformed test year depreciation expense for services is based on the depreciable plant account 380 as of 3/31/91 and a depreciation rate of 3.14 percent and is summarized on Attachment A, Exhibit 1 as revised on October 12, 1992 and Attachment A, Exhibit 1, Schedule B as revised on October 12, 1992 ($109,156).

The parties agree that this amount is fair and reasonable.

Return and Related Income Taxes on Investment to Serve Domtar Gypsum Inc.

The amount for the return and related income taxes on investment to serve Domtar Gypsum Inc. is based on the pre-tax rate of return of 13.19 percent which was agreed upon as part of the settlement agreement on permanent rates and is as summarized on Attachment A, Exhibit 1, Schedule C ($35,513). Staff believes that this amount is fair and reasonable.

Adjustment for Domtar Net Revenues

The Step Adjustment has been reduced in accordance with a formula agreed upon as part of the settlement on permanent rates and reflects an amount equal to pro forma net revenues from Domtar calculated in accordance with Attachment A, Exhibit 1, Schedule D as revised on October 8, 1992 ($508,372). The parties agree that this amount is fair and reasonable.

IV. Issues Involved in the Settlement Agreement

Non-Revenue Producing Expenditures

With regard to the proposed investment in non-revenue producing capital expenditures, the parties agreed to make the following reductions and that these reductions were both just and reasonable:

Joint Sealing/Cathodic Protection	$ 60,710
Replacement Meters/Installs	$ 31,486
Projects/Equipment/Other	$ 18,696
Total Reductions	$ 110,892

These adjustments are summarized in column three of Attachment A, Exhibit 1, Schedule A, as revised on October 12, 1992.

Depreciation

In addition to the above reductions, the parties agreed to reduce depreciation expenses related to Replacement Services. In the permanent rate proceeding, the Company reflected a negative 125 percent salvage value in its depreciation study for services (i.e. depreciation rate of 4.78 percent). At that time, the staff took exception to this percentage and indicated that it would need time to review the basis of the Company's calculations. As a result, zero percent salvage was reflected in the settlement agreement on permanent rates (i.e. depreciation rate of 1.62 percent) with the provision that any difference between the pro formed test year depreciation expense for services proposed by Northern and the depreciation expense for services recommended by staff, subject to audit and review by the Commission, would be included in the Step Adjustment.

In this proposed Step Adjustment proceeding, the Company is again proposing that a negative .25 percent salvage

DR 91-081

NORTHERN UTILITIES, INC.

Report and Order Approving the Settlement

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III. Components of the Settlement Agreement

Return and Related Income Taxes on Non-Revenue Producing Investments

The return and related income taxes on Northern's investment for the period April 1, 1991 through September 30, 1992 is shown on Attachment A, Exhibit 1, as revised on October

12, 1992 ($681,278). The amount of the step adjustment has been calculated using the actual capital expenditures for the above stated period adjusted as a result of the staff audit and the pre-tax rate of return of 13.19 percent and reflecting cost of service principles including the treatment of the deferred tax reserve. Staff believes that this amount is appropriate.

Annualized Depreciation Expense

Annualized depreciation expense for investments other than services is based on Northern's actual plant additions mentioned above and the depreciation rates included in the Settlement Agreement on permanent rates. Annualized depreciation expense for replacement services is based on actual plant additions mentioned above and the depreciation rate of 3.14 percent included in the Settlement Agreement on the Step Adjustment (see below). The parties agree that the expense which results from the use of the 3.14 percent depreciation rate is fair and reasonable. These expenses are summarized on Attachment A, Exhibit 1 as revised on October 12, 1992 ($183,875).

Proformed Test Year Expense For Depreciation

The amount of proformed test year depreciation expense for services is based on the depreciable plant account 380 as of 3/31/91 and a depreciation rate of 3.14 percent and is summarized on Attachment A, Exhibit 1 as revised on October 12, 1992 and Attachment A, Exhibit 1, Schedule B as revised on October 12, 1992 ($109,156).

The parties agree that this amount is fair and reasonable.

Return and Related Income Taxes on Investment to Serve Domtar Gypsum Inc.

The amount for the return and related income taxes on investment to serve Domtar Gypsum Inc. is based on the pre-tax rate of return of 13.19 percent which was agreed upon as part of the settlement agreement on permanent rates and is as summarized on Attachment A, Exhibit 1, Schedule C ($35,513). Staff believes that this amount is fair and reasonable.

Adjustment for Domtar Net Revenues

The Step Adjustment has been reduced in accordance with a formula agreed upon as part of the settlement on permanent rates and reflects an amount equal to pro forma net revenues from Domtar calculated in accordance with Attachment A, Exhibit 1, Schedule D as revised on October 8, 1992 ($508,372). The parties agree that this amount is fair and reasonable.

IV. Issues Involved in the Settlement Agreement

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With regard to the proposed investment in non-revenue producing capital expenditures, the parties agreed to make the following reductions and that these reductions were both just and reasonable:

Joint Sealing/Cathodic Protection	$ 60,710
Replacement Meters/Installs	$ 31,486
Projects/Equipment/Other	$ 18,696
Total Reductions	$ 110,892

These adjustments are summarized in column three of Attachment A, Exhibit 1, Schedule A, as revised on October 12, 1992.

Depreciation

In addition to the above reductions, the parties agreed to reduce depreciation expenses related to Replacement Services. In the permanent rate proceeding, the Company reflected a negative 125 percent salvage value in its depreciation study for services (i.e. depreciation rate of 4.78 percent). At that time, the staff took exception to this percentage and indicated that it would need time to review the basis of the Company's calculations. As a result, zero percent salvage was reflected in the settlement agreement on permanent rates (i.e. depreciation rate of 1.62 percent) with the provision that any difference between the pro formed test year depreciation expense for services proposed by Northern and the depreciation expense for services recommended by staff, subject to audit and review by the Commission, would be included in the Step Adjustment.

In this proposed Step Adjustment proceeding, the Company is again proposing that a negative .25 percent salvage value be reflected in its depreciation rate of 4.78 percent.

Based upon audit and review of the books and records of the Company, staff determined that salvage value of negative 60 percent is appropriate. The impact of this change is to reduce the Company's depreciation rate from 4.78 percent to 3.14 percent. Since the settlement agreement on permanent rates allowed a depreciation rate of only 1.62 percent, the rate adjustment that staff calculates be included in this Step Adjustment is the difference between the 3.14 percent and 1.62 percent. Based on the above and on extensive discussions with the Company, both parties agree that the amount of $109,156 is just and reasonable for annualized depreciation expense to be included in this Step Adjustment . Exhibit A, Schedule B as revised on October 12, 1992 summarizes this adjustment.

COMMISSION ANALYSIS

As part of the settlement on the Company's permanent rates, the staff did not include in rate base the amount of estimated additions during the period subsequent to the test year (i.e., April 1991 through September 1992). The Commission normally does not allow plant added after the end of the test year (i.e., March 31, 1991) unless it is an extraordinary event. However, in view of the comments by the PUC Gas Safety Engineer (see below), staff recommended at the time of the permanent rate settlement that the Commission provide for a rate adjustment in the future to include such additions in a step adjustment. Staff indicated that at a set time interval after the permanent rate adjustment, the Commission could look at the plant additions. Article III of the Settlement Agreement on permanent rates summarized the criteria to be used in the calculation of Step Adjustments.

Based on a review by the PUC Gas Safety Engineer, Northern Utilities has undertaken a major capital project to ensure safe service to its customers. This capital project was undertaken because of a serious problem regarding leaks, the majority of which occurred on the bare steel system. Regarding the bare steel system, the PUC Gas Safety Engineer suggested that the Company approach the problem of corrosion and leaks in two phases. The first phase would schedule replacement of areas that required "immediate repair" and the second phase would address replacement of areas that did not pose "immediate" risk to safety. The Company agreed with the PUC Engineering staff to accelerate its program to replace bare steel mains. The Company and the PUC staff agreed that these replacements are required and both parties recognize that this results in significant dollars being expended on this category of capital expenditures.

Subsequently, it was agreed that the first phase should be implemented over a three year period and that the second phase would be implemented over a ten year period. The three year program considered three factors: first, number of sections to be replaced; second, ability to undertake the project; third, risk to safety; fourth, available capital. In

1990, over 26,000 feet of bare steel was replaced due to corrosion problems. In 1991, over 24,000 feet of bare steel was replaced and the estimate for 1992 is for 15,000 feet to be replaced.

Regarding the ten year program, the Company estimates that there will be between 28,000 feet and 35,000 feet of bare steel replaced per year. This is due to the corrosion program, bare steel replacement due to municipal projects and bare steel replacement due to system improvement.

In addition, it should be understood that the majority of customer services connected to the bare steel mains are also bare steel. It is the Company policy to replace these services with plastic where possible.

With regard to State or Federal safety regulations on corrosion of bare steel systems, the PUC Gas Safety Engineer points out that when there is an area of active corrosion, the Company is required to replace the pipe as soon as practicable. The Office of Pipeline Safety in Washington, DC agreed with the combination of three and ten year programs indicating that the programs satisfied their commitment to safety, and recognized that to require the Company to undertake a program of this magnitude, within one year, would be totally uneconomical and therefore not practicable.

With regard to the impact on the customer, Northern estimates that based on the rate design proposed by the Company, which is currently under review by the staff, the estimated impact of the Step Adjustment amount of $501,450 over all customer classes is roughly 1.9 percent. The estimated impact on the Residential Heating Customer is roughly 1.8 percent. The estimated impact on the Residential Non Heating Customer is roughly 2.2 percent. The estimated impact on the Commercial and Industrial Customer is roughly 2.1 percent.

Overall, the above described program is a sound and positive approach to correct the overall corrosion problem and provide the required safety to customers. Based on the above and based on the audit and review of the Company's books and records, the Commission believes that the Step Adjustment amount of $501,450 is just and reasonable.

Our order will issue accordingly.

Concurring:

October 30, 1992

Douglas L. Patch Chairman	Bruce B. Ellsworth Commissioner	Linda G. Stevens Commissioner

DR 91-081

NORTHERN UTILITIES, INC.

..oo..

O R D E R N O. 20,654

Upon consideration of the foregoing report, which is made a part hereof; it is hereby

ORDERED, that the settlement agreement be, and hereby is, approved.

By order of the New Hampshire Public Utilities Commission this thirtieth day of October, 1992.

Douglas L. Patch Chairman	Bruce B. Ellsworth Commissioner	Linda G. Stevens Commissioner

Attested by:

Wynn E. Arnold
Executive Director & Secretary

STATE OF NEW HAMPSHIRE
BEFORE THE
PUBLIC UTILITIES COMMISSION

NORTHERN UTILITIES, INC.) DOCKET NO. DR 91-081

Stipulation On Proposed Step Adjustment

This Stipulation is entered into this 14th day of October, 1992, by and among Northern Utilities, Inc. ("Northern" or "the Company") and the Staff of the New Hampshire Public Utilities Commission (the "Staff" and the "Commission" respectively) with the intent of resolving the issues discussed herein. Further, it is the desire of the Company and Staff in executing this Agreement to expedite the Commission's consideration and resolution of the issues which are the subject of this Agreement.

ARTICLE I

Introduction

On July 21, 1992 the Commission approved a Settlement Agreement between the Staff and Northern regarding the issues relating to Northern's request for a permanent rate increase. As part of that Settlement Agreement, the parties agreed that it is reasonable to authorize the Company to implement step adjustments in base rates on or about November 1, 1992 and annually thereafter. Settlement Agreement, Article III, p. 4.

On September 21, 1992, Northern filed a petition with the Commission seeking authorization for the initial step adjustment in the amount of $624,907. The Staff conducted a field audit between September 8, and September 25, 1992 and again on October 12, 1992 with respect to Northern's proposed step adjustment including a field visit to Northern's offices in Portsmouth, NH, and issued over 115 audit requests to which the Company responded.

Following extensive discussions the Staff and Northern reached agreement on the issues in this proceeding as set forth in Articles II and III.

ARTICLE II

The parties agree that it is reasonable to authorize Northern to increase its base rates effective with the first November 1992 billing cycle to reflect recovery of the following as summarized on revised Exhibit I:

1. A return and related income taxes on Northern's investment in certain non-revenue producing capital expenditures for the period April 1, 1991 through September 30, 1992, as shown on revised Schedule A. The amount of the step adjustment has been calculated using the actual plant additions for the ~~above stated~~ period April 1, 1992 through August 31, 1992 adjusted as a result of the Staff audit and the Stipulation positions of the parties and a pre-tax rate of return of 13.19% and reflecting cost of service principles including the treatment of the deferred income tax reserve. The amount of the step adjustment reflecting Replacement Mains for the period September 1 through September 30, 1992 shall be subject to adjustment in accordance with a Staff audit to be completed by October 23, 1992 and in no event shall be greater than the amounts reflected on revised Schedule A.

EPC EJL

EPC EJL

2. Annualized depreciation expense on the actual plant additions referenced in paragraph 1 above based on the depreciation rates in the Settlement Agreement for investments other than services and on the depreciation rate for services of 3.14% determined by the Staff to be fair and reasonable as shown on revised Schedule A.
3. The difference between the pro formed test year depreciation expense for services in the Settlement Agreement and the depreciation expense for services recommended by Staff as fair and reasonable and as shown on revised Schedule B.
4. The return and related income taxes of $269,242 in rate base reflecting capital investments used to serve Domtar Gypsum, Inc. ("Domtar"), as shown on revised Schedule C.

The step adjustment has been reduced by an amount equal to pro forma net revenues from Domtar calculated as follows:

(Actual historical firm volumes for the twelve-month period ending September 30, 1992) times (the non-gas portion of the rates to serve Domtar as approved in the Company's recent rate case less ($41,393 test year net transportation revenues for Domtar built into base rates).

ARTICLE III

Conditions

The making of this Stipulation shall not be deemed in any

Exhibit 1
Revised 10/12/92

Northern Utilities Inc.
New Hampshire Division
Summary of Proposed Step Adjustment Revenues

	(1)	(2)	(3)
1	Non-Revenue Producing Investments:		
2	Return and Related Income Taxes	Schedule A	$681,278
3	Annualized Depreciation Expense	Schedule A	183,875
4			
5	Proformed Test Year Depreciation		
6	Expense for Services	Schedule B	109,156
7			
8	Return and Related Income Taxes on		
9	Investment to Serve Domtar Gypsum Inc.	Schedule C	35,513
10			
11	Firm Net Revenues for Domtar Gypsum Inc.	Schedule D	(508,372)
12			-------
13	Proposed Step Adjustment Revenues		$501,450
			=======

Northern Utilities, Inc
New Hampshire Division

Proposed Step Adjustment Related to Non-Revenue Additions to Plant in Service

	April 1991 - August 1992	Actual September 1992	Less Adjustments (1)	Revised Total	Depreciation Rates	Annualized Depreciation Expense
Replacement Mains	$2,984,652	$473,942		$3,458,594		
Gosling Road	403,402			403,402		
Joint Sealing / Protection	117,102	10,806	(60,710) (A)	67,198		
Sub-Total	$3,505,156	$484,748	($60,710)	$3,929,194	3.05%	$119,840
Replacement Services	536,564	62,840		599,404	3.14% (D)	18,821
Replacement Meters/Installs	246,378	27,877	(31,486) (B)	242,769	3.36%	8,157
Regulator Station Equipment	92,433	507		92,940	5.05%	4,693
Projects/Equipment/Other	303,219	56,133	(18,696) (C)	340,656	9.50%	32,362
	$4,683,756	$632,165	($110,892)	$5,204,963		$183,875

Total Non-Revenue Producing (April 1991 through September 1992)	$5,204,963
Less: Deferred Income Taxes on Closes to Plant	39,852
Sub-Total Rate Base	$5,165,111
Return & Related Income Taxes at Pre-Tax Rate of Return of 13.19%	$681,278

Revenue Requirements for Step Adjustment to be Effective November 1, 1992:

Return on Plant Investment	$681,278
Annual Depreciation Expense	$183,875

(1) - See Attached Schedule for Notes A, B C & D.

Northern Utilities, Inc.
New Hampshire Division
Audit Findings Adjustments Agreed to by the NHPUC Staff and Company On October 6, 1992

A: Joint Sealing/Cathodic Protection (Audit Find #5)

Note: Agreement to split costs after adjustment for Meter Protection on 50/50 basis

Actual Closes to Plant (4/91-9/92)	$117,102	
Closes to Plant (9/92)	10,806	
Schedule A - JointSealing/Protection Total Filed with NHPUC on 9/21/92		$127,908
Total Closes to Plant	127,908	
Less: NHPUC accepted Meter Protection costs	(6,488)	
Basis for Settlement per Audit Find #5	121,420	
Settlement percentage of 50% after adjustment - Agreed Rate Base Reduction		(60,710)
Adjusted Closes to Plant		$67,198

B: Replacement Meters/Installs (Audit Find #4 + Attached Page 2 of 2)

Note: Agreement to split costs after adjustment for Replacement Meters to 29% of total costs on 50/50 bases

Total Meter Costs (Data Response #95, Attachment B)		$196,787	
Per company (DR - #95 Attachment D)	61%		
Per company (DR - #95 Attachment C)	29%	32%	
Basis for Settlement per Audit Find #4		62,972	
Settlement percentage of 50% after adjustment - Agreed Rate Base Reduction			($31,486)

C: Projects/Equipment/Other (Audit Finds #1,2 and 3)

Note: Reduction for Audit Findings #2 & #3 and 50/50 basis on the PC Hardware of $11,400)

Actual Closes to Plant (4/91-8/92)	$303,219	
Closes to Plant - 9/92 (excludes Software)	56,133	
Schedule A - Projects/Equipment/Other		$359,352
Less: Removal of Software Costs (Audit Find #1):		
Development Software CBT	(2,414)	
Sales Rep Tool Kits Software Costs	(7,482)	
PC Equipment/Hardware Costs ($11,400 *50%)	(5,700)	
Distribution Work Order Management	(400)	
Deferred Debit - Demand Side Management	(2,115)	
	(18,111)	
Less: Massachusetts Sales Tax Adjustment (Audit Find #2)	(230)	
Less: Communication Equipment mischarged to NH (Audit Find #3)	(355)	
Settlement - Agreed Rate Base Reduction		(18,696)
Adjusted Closes to Plant		$340,656

D: Depreciation Study Results dated October 6, 1992 (Attachment#1)

Note: Rate of 3.14% for Replacement Services with Estimated Future Net Salvage of Negative 60%

Schedule B
Revised 10/12/92

Northern Utilities Inc.
New Hampshire Division
Proposed Step Adjustment for Proformed Test Year
Depreciation Expense for Services

(1)	(2) Per DR91-081 Settlement Agreement	(3) Per Staff (A)	(4) Difference
Depreciable Plant, Account 380, As of, 3/31/91	$7,181,291	$7,181,291	
Depreciation Rate	1.62%	3.14%	
Depreciation Expense Adjustment	$116,337	$225,493	$109,156

(A) NHPUC Staff and Company settled on a Depreciation Rate of 3.14% on October 6, 1992. This agreement was based on Staff's Draft Audit report prepared by Stephen Frink, PUC Examiner dated October 6, 1992.

DOMTAR NET REVENUES
October 1991 – September 1992
Based on Rates Effective August 1992

	Therms	Net Revenue Rate	Net Revenues
October 1991	660,561	0.0410	$27,140
November	438,976	0.1321	$58,046
December	401,512	0.1321	$53,097
January 1992	476,661	0.1321	$63,024
February	573,329	0.1321	$75,794
March	568,960	0.1321	$75,217
April	517,632	0.1321	$68,436
May	[illegible]	[illegible]	[illegible]
June	[illegible]	0.0410	[illegible]
July	[illegible]	[illegible]	[illegible]
August	[illegible]	0.0410	[illegible]
September	652,945	0.0410	$26,828
Total Net Revenues			$549,766
Less Transportation Revenues			[illegible]
Domtar Revenue Adjustment			$508,372

Northern Utilities Inc.
New Hampshire Division

Schedule C

Proposed Step Adjustment for Return and Related Income Taxes
on Investment to Serve Domtar Gypsum, Inc.

	(1)	(2)
1	Domtar Investment (Schedule NU –3–4–2)	$269,242
2		
3	Pre Tax Rate of Return	13.19%
4		------
5	Domtar Return and Related Income Tax Adjustment	$35,513
6		======

COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF TELECOMMUNICATIONS AND ENERGY

RESPONSE OF BAY STATE GAS COMPANY TO THE
SECOND SET OF INFORMATION REQUESTS FROM THE ATTORNEY GENERAL
D. T. E. 05-27

Date: June 6, 2005

Responsible: Danny G. Cote, General Manager

AG-2-28 Identify all management and executive level individual(s) at both the Company and Northern Utilities, a Bay State subsidiary, responsible for corrosion monitoring and scheduling replacement of mains and services from 1985 to 2005.

Response: Please see Attachment AG-2-28.

Year	Company	Most Senior Executive	Direct Report	Direct Report	Direct Report	Direct Report	Title	Department
1985	BSG/Northern	Not Available						
1986	BSG	C.G. Setian					Sr. Vice President Operations	Operations
			P.W. Lashoto				Director Operations	Operations
				W.R. Ainey			Systems Supervisor	Corrosion Control
				E.J. Collins			Compliance Engineer	Engineering
							Manager	System Planning
			J.A. Burke				Vice President	Sprinfield Division
				T.J. Dulchinos			Manager	Planning and Engineering
			S.R. Jeffery				Vice President	Brockton Division
				R.S. Reardon			Manager	Planning and Engineering
				B.I. Turner			Manager	Distribution
					S.A. Larson		Supervisor	Corrosion
			J.R. Snow				Vice President	Lawrence Division
				J.D. Martin			Manager	Distribution (Corrosion)
	Northern	W. Ivancivec						
			D. Cote					
			J. Wilbur					
1987	BSG/Northern	C.G. Setian					Sr. Vice President Operations	Operations
			P.W. Lashoto				Director Operations	Operations
				W.R. Ainey			Systems Supervisor	Corrosion Control
				E.J. Collins			Compliance Engineer	Engineering
							Manager	System Planning
			J.A. Burke				Vice President	Sprinfield Division
				T.J. Dulchinos			Manager	Planning and Engineering
				C.A. Tyburski			Manager	Distribution
			S.R. Jeffery				Vice President	Brockton Division
				R.S. Reardon			Manager	Planning and Engineering
				B.I. Turner			Manager	Distribution
					S.A. Larson		Supervisor	Corrosion
			J.R. Snow				Vice President	Lawrence Division
				E.M. Wencis			Manager	Distribution/Engineering/Corrosion
	Northern	W. Ivancivec						
			D. Cote					
			J. Wilbur					
1988		C. Setian	J. R. Snow				Vice President	Lawrence Division
				Dan Cote				
					Mel Roast			
			J. A. Burke				Vice President	Springfield Division
			S. R. Jeffery				Vice President	Brockton Division
1989		Not available						
1990	Northern	Not available						
			D. Cote					
			A. Petrosino					
			R. Aziz					
1991		Not available						
1992		Not available						

Year	Company	Most Senior Executive	Direct Report	Direct Report	Direct Report	Direct Report	Title	Department
1993	BSG/Northern	C.G. Setian					Sr. Vice President Operations	Operations
			P.W. Lashoto				Director	Engineering/Purchasing
	Northern		V.H. Platania				Manager	Northern Construction
	BSG/Northern	P.G. Ford					Sr. Vice President	HR / Division Management
			P.W. Kallaugher				Vice President	Brockton
			J.A. Burke				Vice President	Springfield
			J.R. Snow, Jr.	R. Aziz			Vice President	Northern
			H. Bickford					
1994	BSG/Northern							
			P.W. Lashoto				Director	Planning and Engineering
				F.A. Desautels			Manager	System Planning
	BSG			E. Hebert			Manager	Construction
	Northern			V.H. Platania			Manager	Construction
	BSG/Northern	P.G. Ford					Sr. VP	Operations
			P.W. Kallaugher				VP	Brockton
				R.S. Reardon			Manager	Planning and Engineering
			J.A. Burke				VP	Springfield
				T.J. Dulchinos			Manager	Planning and Engineering
			J.R. Snow				VP	Northern
				E.M. Wencis			Manager	Planning and Engineering
1995	BSG/Northern							
			P.W. Lashoto				Director	Planning and Engineering
	BSG							
	Northern			V.H. Platania			Manager Operatins	
	BSG/Northern	J.L. Singer					Executive VP and COO	
			P.W. Kallaugher				VP	Brockton
				R.S. Reardon			Manager	Planning and Engineering
				F.W. St. Cyr			Manager	Distribution (Corrosion)
			J.A. Burke				VP	Springfield
				T.J. Dulchinos			Manager	Planning and Engineering
			J.R. Snow				VP	Northern
				E.M. Wencis			Manager	Planning and Engineering
				R.T. Aziz			Manager	Operations (Dist/Const/Corrosion) - Lawrence
				D.G. Cote			Manager	Operations (Dist/Const/Corrosion) - ME
				A.A. Petrosino			Manager	Operations (Dist/Const/Corrosion) - NH
				V.H. Platania			Manager	Gas Operations
1996	BSG/Northern	J.L. Singer						
			J.D. Simpson				Leader	Local Transportation
				J.R. Snow			Leader	System Maintenance & Construction
	BSG/Northern				D.G. Cote		Leader	Maintenance & Construction
						M.L. Laghetto	Field Location Leader, Maintenance	Brockton
						M. Knodler	Field Location Leader, Maintenance	Springfield
						Open	Field Location Leader, Maintenance	Northern
						F.W. St. Cyr	Field Location Leader, Construction	Brockton
						K.R. Dalton	Field Location Leader, Construction	Northern
						T.J. Dulchinos	Field Location Leader, Construction	Springfield
	BSG/Northern				P.W. LaShoto		Leader	Engineering
1997	BSG/Northern	J.L. Singer					President and COO	
			J.D. Simpson				Leader	Local Transportation
				J.R. Snow			Leader	System Maintenance and Construction
				P.W. LaShoto			Leader	Engineering, Plants and Facilities
				D.G. Cote			Leader	Maintenance and Construction

Year	Company	Most Senior Executive	Direct Report	Direct Report	Direct Report	Direct Report	Title	Department
1998	BSG/Northern	J.L. Singer					President and Co-CEO	
			J.D. Simpson				Sr. V.P. and Leader	Utilitiy Segment
				J.R. Snow			Leader	System Maintenance and Construction
				P.W. LaShoto			Leader	Engineering, Plants and Facilities
				D.G. Cote			Leader	Maintenance and Construction
1999	BSG/Northern	J.W. Yundt					President and CEO	
			K.M. Margossian				Senior V.P. Operations	
	BSG			J.R. Snow			V.P. General Manager	Southern
	Spfld				K.R. Dalton		Operations Manager	Springfield
						T.J. Dulchinos	Manager, Distribution	Springfield
	Broc				F.W. St.Cyr		Operations Manager	Brockton
						M.L. Laghetto	Manager, Distribution	Brockton
	Northern			D.G. Cote			V.P. General Manager	Northern
					V.H. Plantia		Operations Manager	Lawarence
					S.A. Eon		Operations Manager	Portsmouth
					M.J. Roast		Operations Manager	Portland
					R.E. Johnson		Manager, Engineering	Northern
	BSG/Northern			P.W. Lashoto			Director	Engineering and Construction
2000	BSG/Northern	J.W. Yundt					President and CEO	
			K.M. Margossian				Sr. VP Operations	
				D.G. Cote			V.P. General Manager	Northern
					R.E. Johnson		Manager Engineering	
					M.J. Roast		Operations Manager Portland	
					S.A. Eon		Operations Manager Portsmouth	
					V.H. Plantia		Operations Manager Lawrence	
				Open			V.P. General Manager	Southern
					F.W. St Cyr		Operations Manager Brockton	
						M.L. Laghetto	Manager Distribution	
					K.R. Dalton		Operations Manager Springfield	
						T.J. Dulchinos	Manager Distribution	
				P.W. Lashoto			Director Engineering and Construction	
2001	BSG/Northern							COH/CKY/BSG
		K.M. Margossian					Executive Vice President and COO	
				D.G. Cote			V.P. Operations	
					F.W. St. Cyr		Mgr Operations Brockton	
					M.L. Laghetto		Manager, Distribution	
					K. Dalton		Mgr Operations Springfield	
						T.J. Dulchinos	Mgr Distribution	
					V.H. Platania		Mgr, Operations Lawrence	
					S.A. Eon		Mgr, Operations Portsmouth	
					Mel Roast		Mgr. Operations Porttland	
2002		K.M. Margossian					Executive Vice President and COO	
				D.G. Cote			Vice President Operations	
							General Manager BSG/Northern	
					F.W. St. Cyr		OCM	
					M.L. Laghetto		OCM	
					P.A. Bellino		OCM	
					P. Rogosienski		OCM	
					R.E. Morin		OCM	

Year	Company	Most Senior Executive	Direct Report	Direct Report	Direct Report	Direct Report	Title	Department
2003								
		D.G. Cote					General Manager	
				F.W. St. Cyr			OCM	Brockton
				M.L. Laghetto			OCM	Lawrence
				P.A. Bellino			OCM	Springfield
				P. Rogosienski			OCM	Portland
				R.E. Morin			OCM	Portsmouth
				D.E. Merriam			Mgr, Corrosion/Leakage/Facilites	
				K.R. Dalton			Sr Engineer	
2004								
		D.G. Cote					General Manager	
				F.W. St. Cyr			OCM	
				M.L. Laghetto			OCM	
				P.A. Bellino			OCM	
				P. Rogosienski			OCM	
				J.A. Dasilva			OCM	
				D.E. Merriam			Mgr, Corrosion/Leakage/Facilities	
				K.R. Dalton			Mgr, Engineering and Construction	
2005								
	BSG/Northern	D.G. Cote					General Manager	
				F.W.St. Cyr			OCM	
				M.L. Laghetto			OCM	
				P.A. Bellino			OCM	
				P. Rogosienski			OCM	
				J.A. Dasilva			OCM	
				D.E. Merriam			Mgr, Corrosion/Leakage/Facilities	
				K.R. Dalton			Mgr, Corrosion/Leakage/Facilities	

COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF TELECOMMUNICATIONS AND ENERGY

RESPONSE OF BAY STATE GAS COMPANY TO THE
SECOND SET OF INFORMATION REQUESTS FROM THE ATTORNEY GENERAL
D. T. E. 05-27

Date: June 6, 2005

Responsible: Danny G. Cote

AG-2-29 Produce all reports, memorandums and analysis concerning the cause of the corrosion and leak rate on Northern Utilities steel related to the orders produced in response to AG 2-27.

Response: Northern Utilities did not create any reports or memorandums, nor did it conduct any formal analysis as to the actual cause of the corrosion and leak rate at the time. The pipe had reasonably reached its useful life and leak rates were escalating. Based on its operating experience, Bay State concluded that the corrosion was due to the naturally occurring process when unprotected steel is placed in a relatively low resistive soil and the electrolytes in the steel return to their original state over time.

COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF TELECOMMUNICATIONS AND ENERGY

RESPONSE OF BAY STATE GAS COMPANY TO THE
SECOND SET OF INFORMATION REQUESTS FROM THE ATTORNEY GENERAL
D. T. E. 05-27

Date: June 6, 2005

Responsible: Danny G. Cote, General Manager

AG-2-30 Please identify the manufacture by name, address and phone number of the mains and services that are to be replaced by the Company's proposed replacement program.

Response: Given the age of these facilities, this information is no longer maintained by the Company. Bay State is continuing to seek information related to this request and will provide such information if it is able to locate it.

COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF TELECOMMUNICATIONS AND ENERGY

RESPONSE OF BAY STATE GAS COMPANY TO THE
SECOND SET OF INFORMATION REQUESTS FROM THE ATTORNEY GENERAL
D. T. E. 05-27

Date: June 6, 2005

Responsible: Danny G. Cote, General Manager

AG-2-31 Describe the technical specifications of the mains or services purchased from each manufacturer listed in response to AG 2-30. Label on the maps produced in response to AG-2-1(e) the name of the manufacture of the mains and services and the date(s) by year of installation.

Response: Given the age of these facilities, this information is no longer maintained by the Company, especially with regard to bare steel. Bay State will continue to seek this information and will supplement this response if it is able to locate it.

COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF TELECOMMUNICATIONS AND ENERGY

RESPONSE OF BAY STATE GAS COMPANY TO THE
SECOND SET OF INFORMATION REQUESTS FROM THE ATTORNEY GENERAL
D. T. E. 05-27

Date: June 6, 2005

Responsible: Danny G. Cote, General Manager

AG-2-32 Has the Company contacted the manufacture of the mains and services listed in the response to AG-2-30 to: a) evaluate the cause of the accelerating leak rate, b) discuss the possibility of manufacturing defects, or c) make a product warranty claim? Identify who at the manufacturer was contacted and describe in detail the results of any discussion. Produce all documents related to contact with the manufacturers on topics (a) - (c).

Response: No. Please see Bay State's responses to AG-2-30 and AG-2-31.

By way of explanation, Bay State believed that the facilities would last over 40 years. The facilities slated for replacement in Bay State's SIR are typically between 45 and 80 years old, with the majority between 50 and 65. That being the case, Bay State does not believe that it would be able to maintain a viable claim that the material was defective or had not performed as warranted, because in fact it was in service to Bay State's customers (and therefore served Bay State) as long or longer than its expected life.

COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF TELECOMMUNICATIONS AND ENERGY

RESPONSE OF BAY STATE GAS COMPANY TO THE
SECOND SET OF INFORMATION REQUESTS FROM THE ATTORNEY GENERAL
D. T. E. 05-27

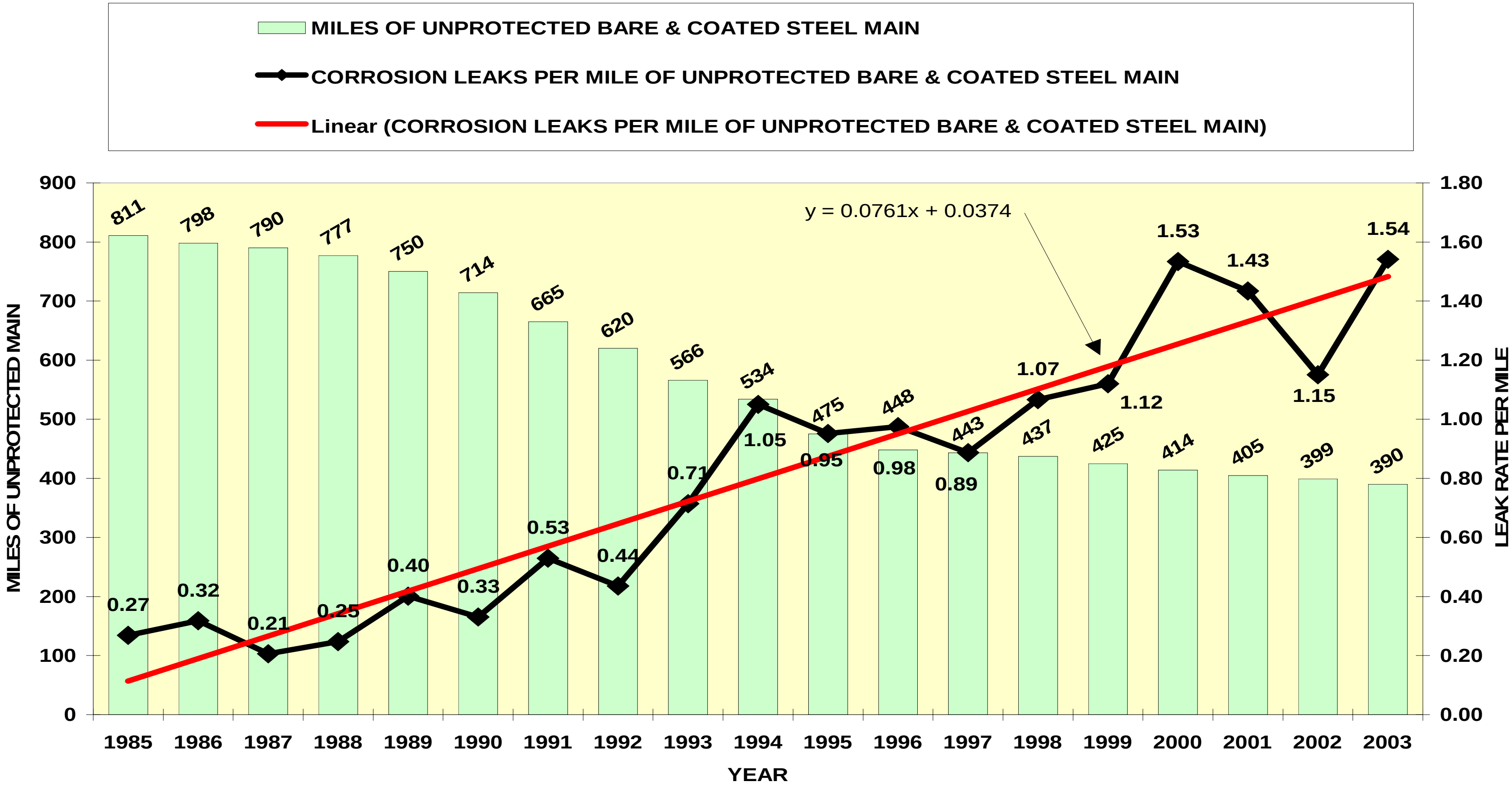
Date: June 6, 2005

Responsible: Danny G. Cote, General Manager

AG-2-33 Please produce all documents from presentations and reports to state and federal regulators from 1995 to 2005 regarding the Company's pipe and services corrosion leaks.

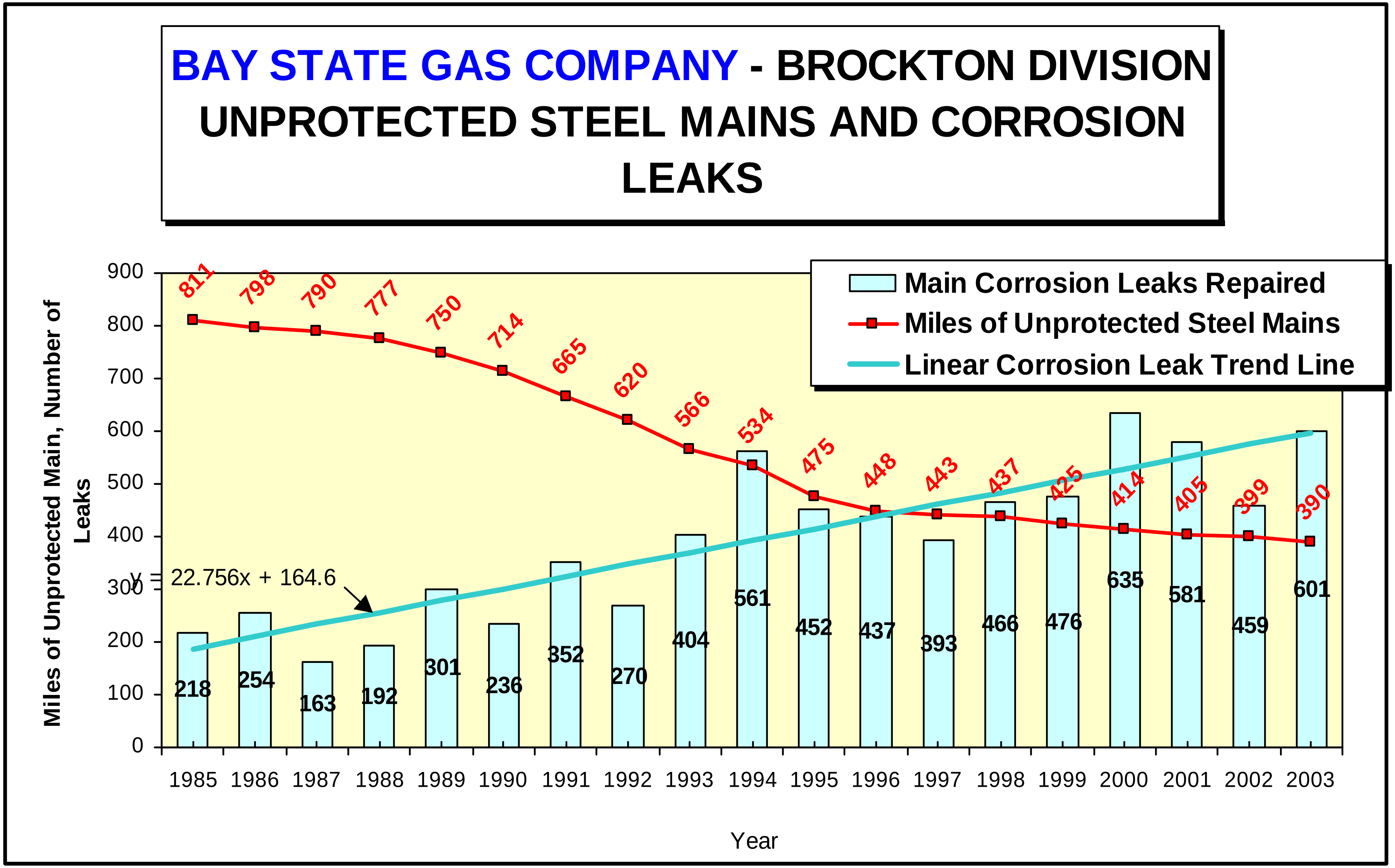
Response: Please see Attachment AG-2-33.

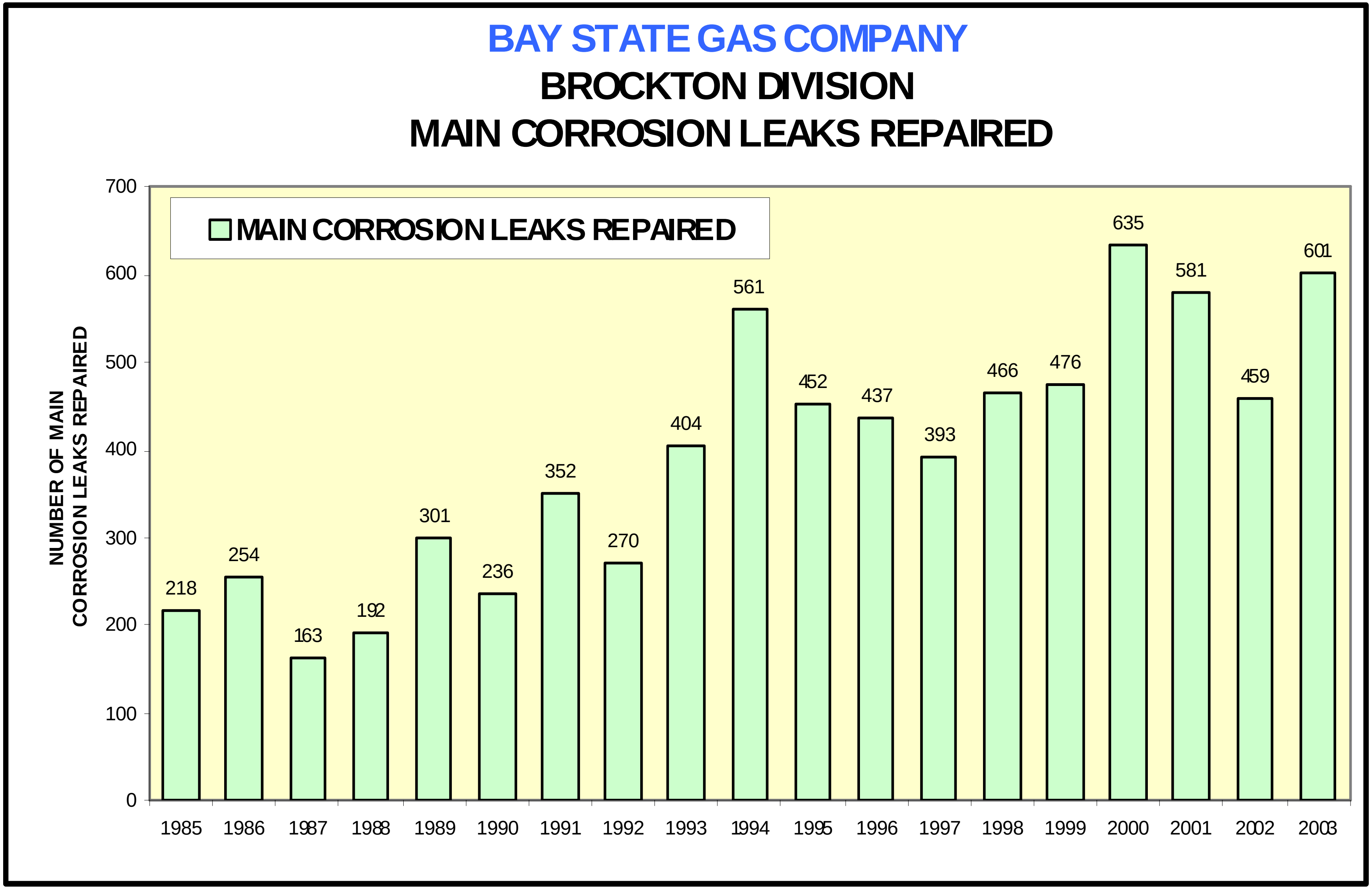
BAY STATE GAS - BROCKTON MA - MILES OF UNPROTECTED BARE & COATED STEEL MAIN AND CORROSION LEAK REPAIR RATE PER MILE



NiSource Energy Distribution Group

Bay State Gas Company




BAY STATE GAS COMPANY
BROCKTON DIVISION
MAIN CORROSION LEAKS REPAIRED
MAIN CORROSION LEAKS REPAIRED
NUMBER OF MAIN CORROSION LEAKS REPAIRED
0
100
200
300
400
500
600
700
218
254
163
192
301
236
352
270
404
561
452
437
393
466
476
635
581
459
601
1985
1986
1987
1988
1989
1990
1991
1992
1993
1994
1995
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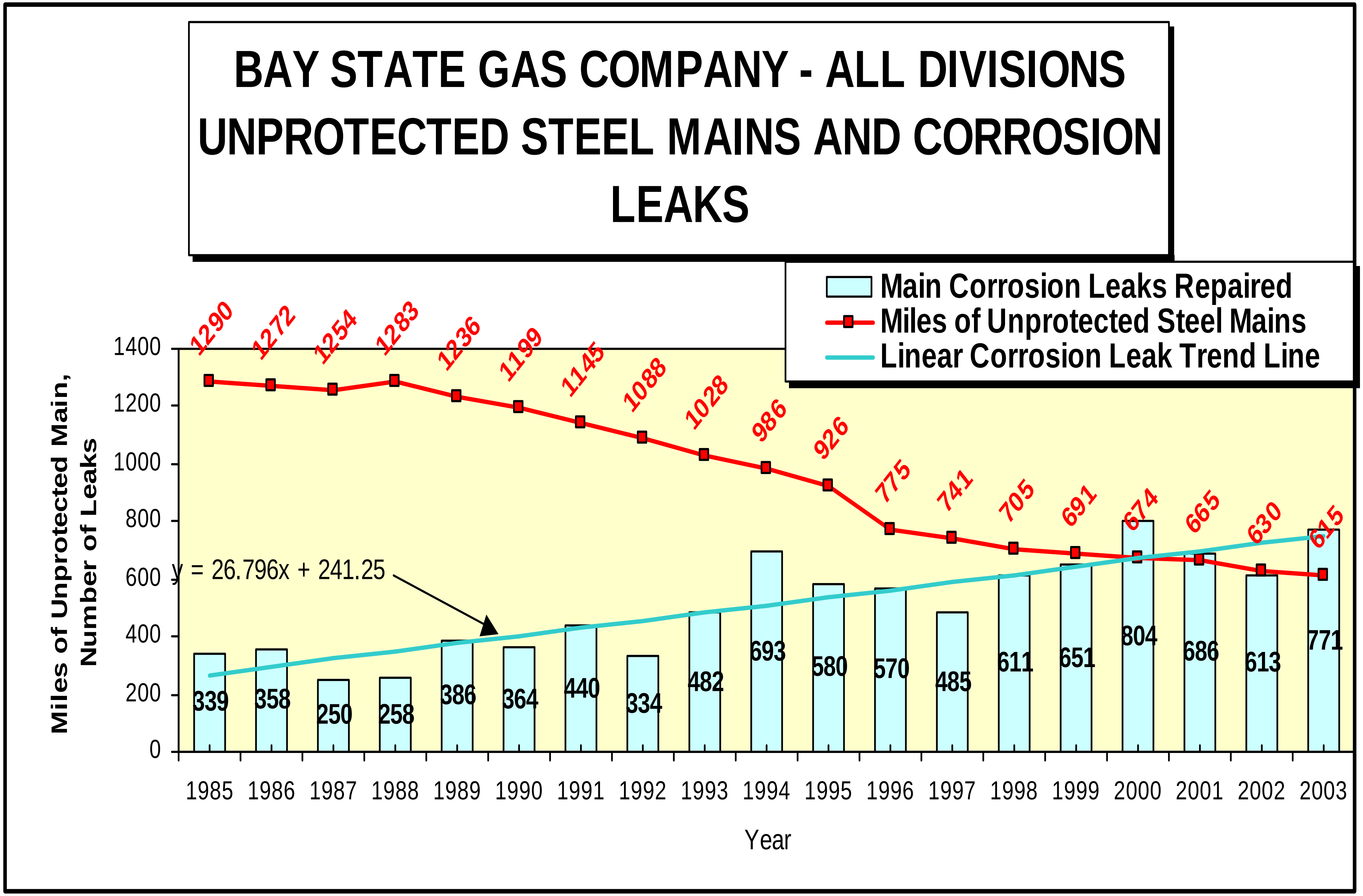
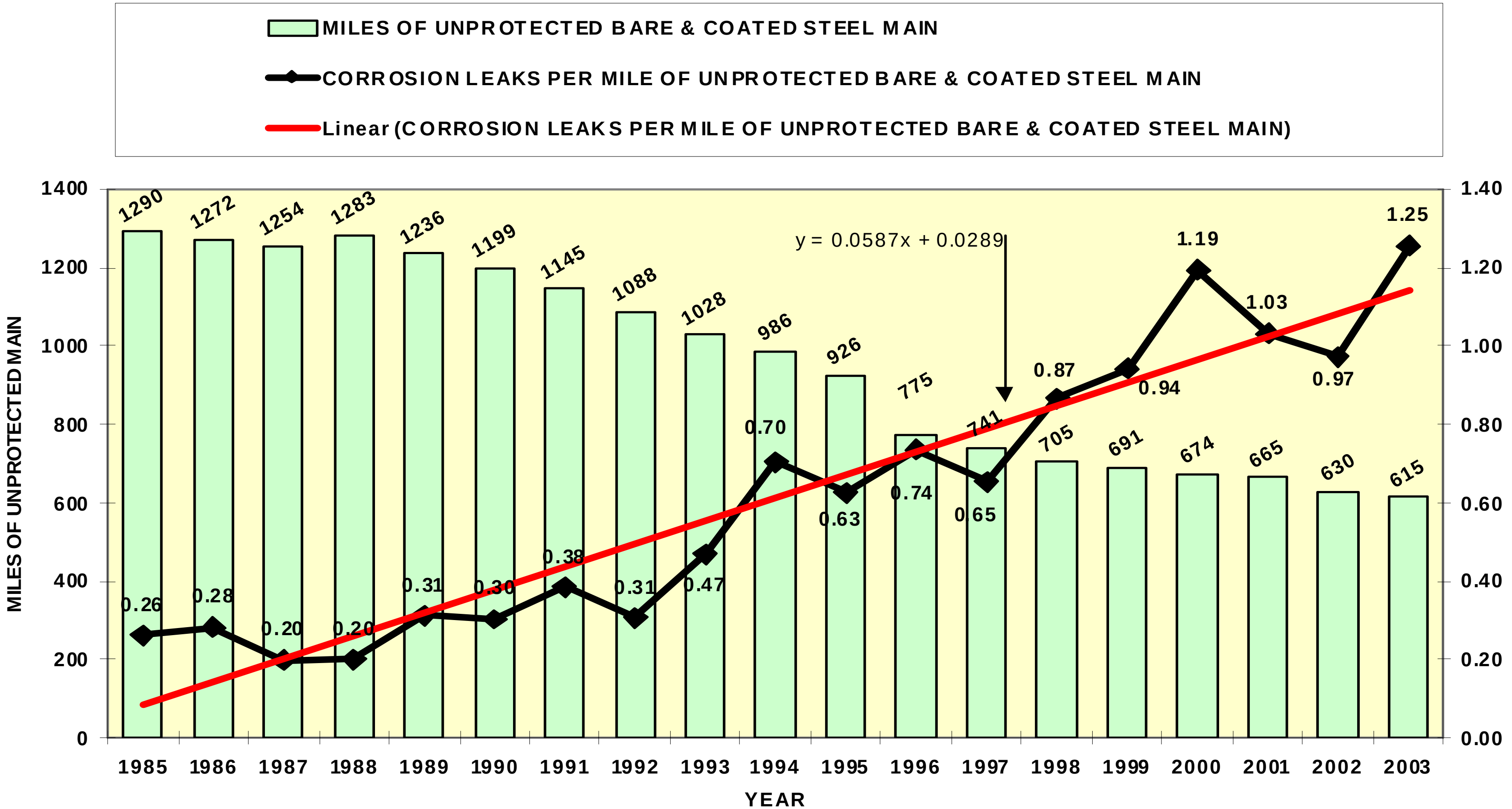
1998
1999
2000
2001
2002
2003

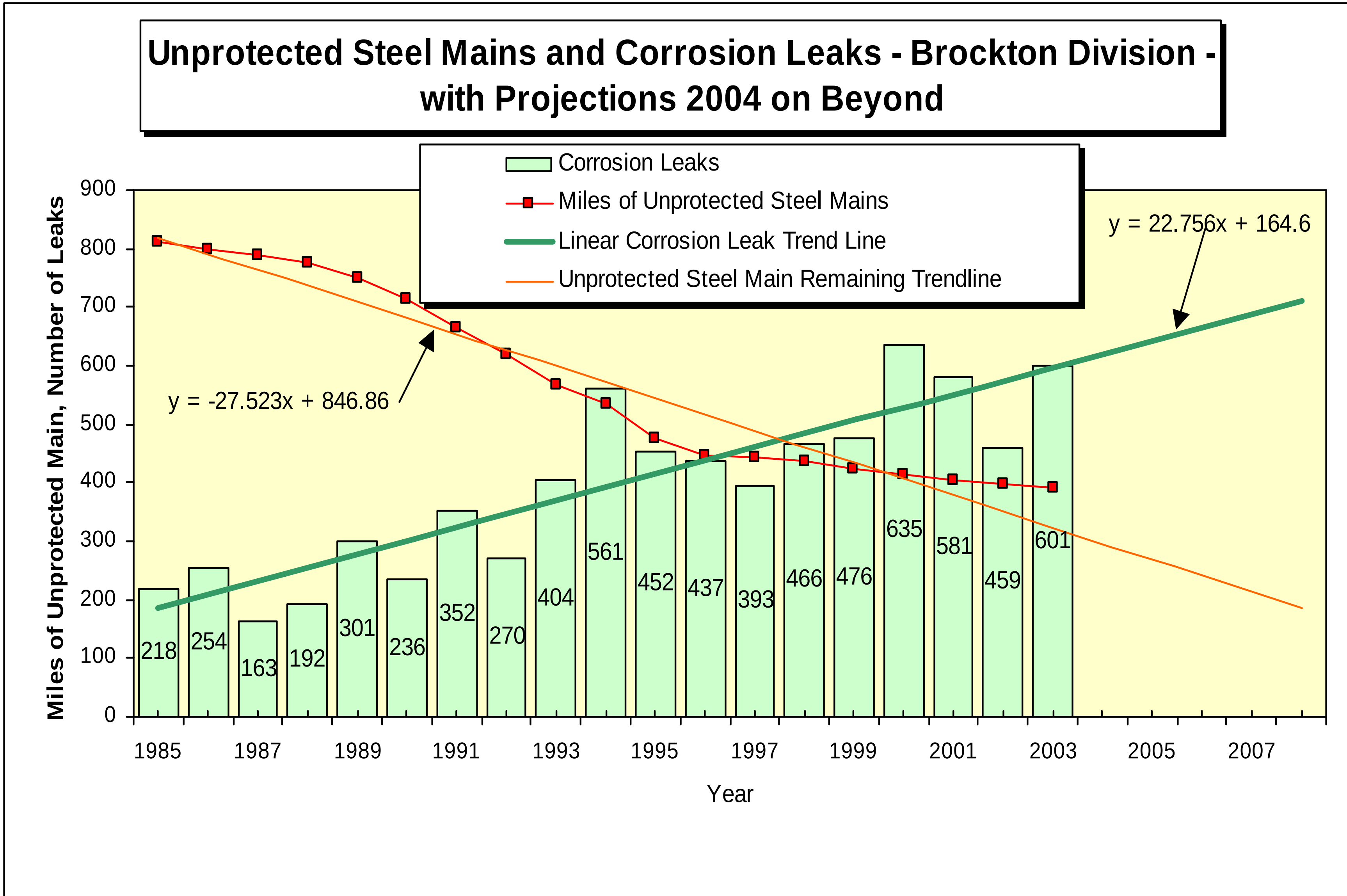
Bay State Gas Company

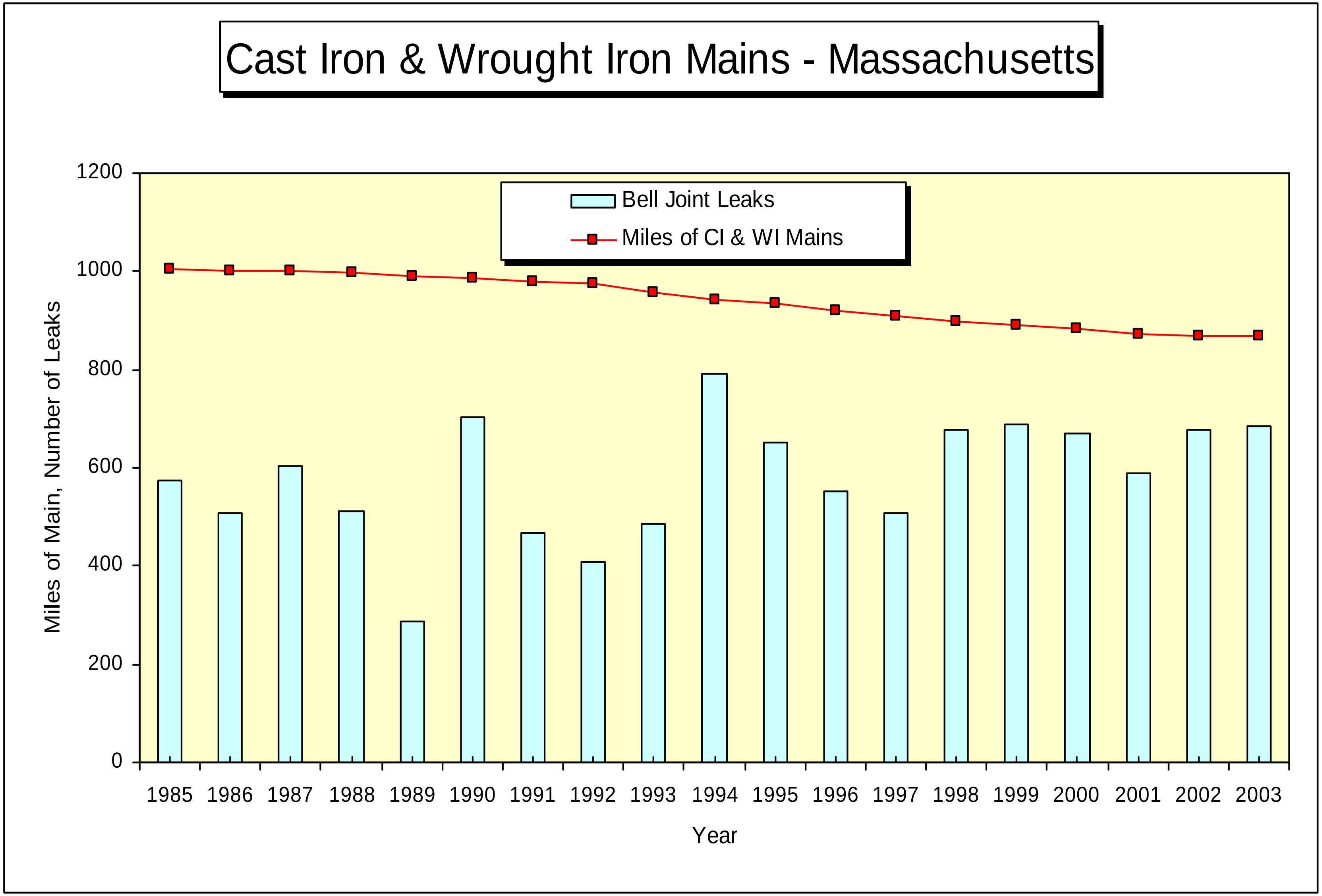


BAY STATE GAS - ALL DIVISIONS
MILES OF UNPROTECTED BARE & COATED STEEL MAIN
AND CORROSION LEAK REPAIR RATE PER MILE

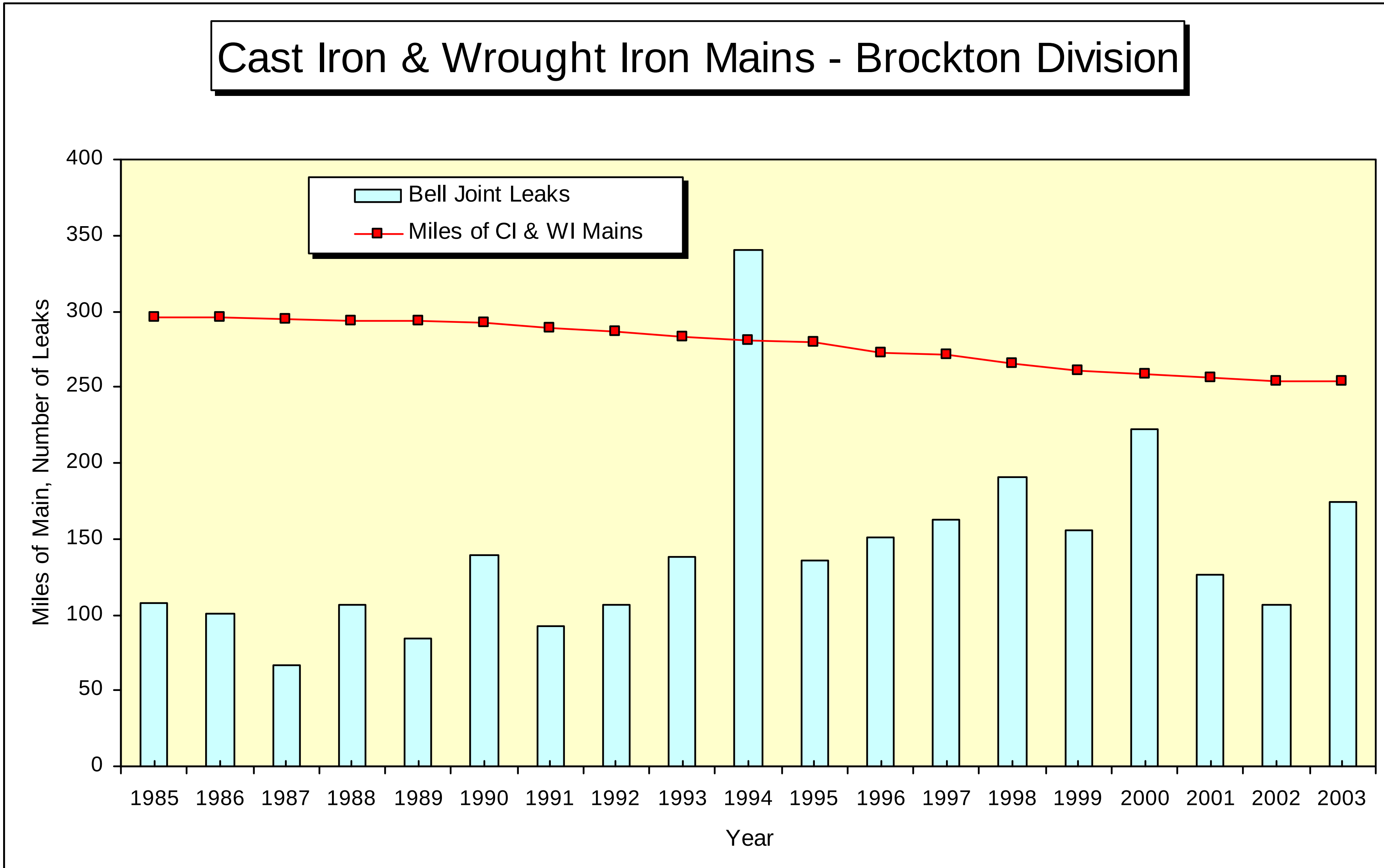


Bay State Gas Company

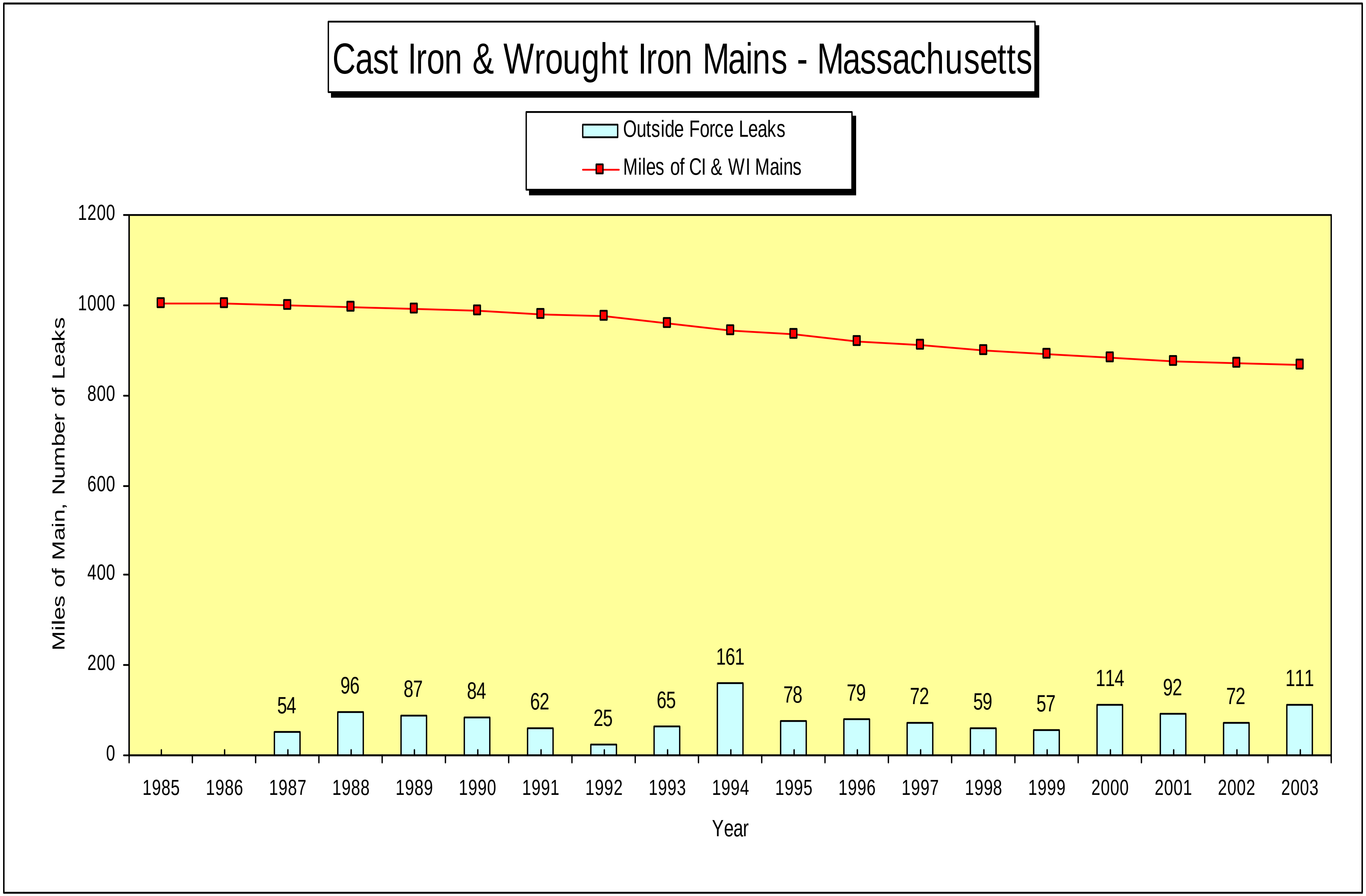



Cast Iron & Wrought Iron Mains - Massachusetts
Bell Joint Leaks
Miles of CI & WI Mains
Miles of Main, Number of Leaks
0
200
400
600
800
1000
1200
1985
1986
1987
1988
1989
1990
1991
1992
1993
1994
1995
1996
1997
1998
1999
2000
2001
2002
2003
Year

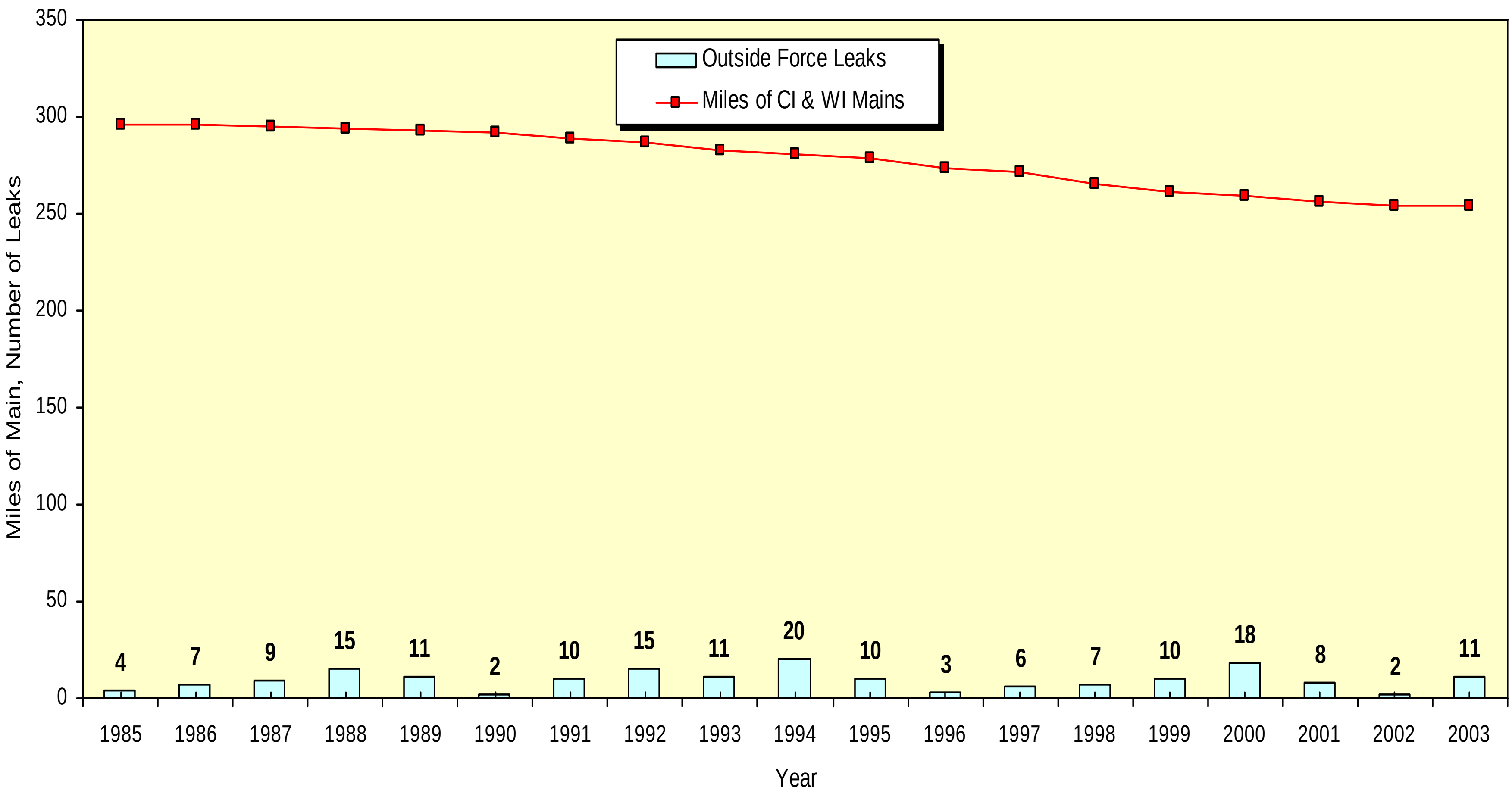
Bay State Gas Company



Bay State Gas Company



Cast Iron & Wrought Iron Mains - Brockton Division



COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF TELECOMMUNICATIONS AND ENERGY

RESPONSE OF BAY STATE GAS COMPANY TO THE
SECOND SET OF INFORMATION REQUESTS FROM THE ATTORNEY GENERAL
D. T. E. 05-27

Date: June 6, 2005

Responsible: Danny G. Cote, General Manager

AG-2-41 Create a bar graph with the years 1990 to 2005 along x-axis and Company costs of coated steel pipe without cathodic protection main replacements per year along the y-axis. Include all work papers, calculations and assumptions used to calculate the costs of these main replacements per year.

Response: Bay State does not maintain this information in the format requested but is attempting to create the graph sought. Bay State will update or supplement this response when the information is available.

COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF TELECOMMUNICATIONS AND ENERGY

RESPONSE OF BAY STATE GAS COMPANY TO THE
SECOND SET OF INFORMATION REQUESTS FROM THE ATTORNEY GENERAL
D. T. E. 05-27

Date: June 6, 2005

Responsible: Danny G. Cote, General Manager

AG-2-42 Create bar graphs with the years 1990 to 2005 along x-axis and the costs of coated steel pipe without cathodic protection main replacements per year along the y-axis for the Springfield, Lawrence and Brockton service territories. Include all work papers, calculations and assumptions used to calculate the costs of these main replacements per year.

Response: Bay State does not maintain this information in the format requested but is attempting to create the graph sought. Bay State will update or supplement this response when the information is available.

COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF TELECOMMUNICATIONS AND ENERGY

RESPONSE OF BAY STATE GAS COMPANY TO THE
SECOND SET OF INFORMATION REQUESTS FROM THE ATTORNEY GENERAL
D. T. E. 05-27

Date: June 6, 2005

Responsible: Danny G. Cote, General Manager

AG-2-43 Create a bar graph with the years 1990 to 2005 along x-axis and Company costs of coated steel without cathodic protection services replacements per year along the y-axis. Include all work papers, calculations and assumptions used to calculate the costs of these service replacements per year.

Response: Bay State does not maintain this information in the format requested but is attempting to create the graph sought. Bay State will update or supplement this response when the information is available.

COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF TELECOMMUNICATIONS AND ENERGY

RESPONSE OF BAY STATE GAS COMPANY TO THE
SECOND SET OF INFORMATION REQUESTS FROM THE ATTORNEY GENERAL
D. T. E. 05-27

Date: June 6, 2005

Responsible: Danny G. Cote, General Manager

AG-2-44 Create bar graphs with the years 1990 to 2005 along x-axis and the costs of coated steel without cathodic protection services replacements per year along the y-axis for the Company's service territories in the cities of Springfield, Lawrence and Brockton. Include all work papers, calculations and assumptions used to calculate the costs of these services per year for each of the cities.

Response: Bay State does not maintain this information in the format requested but is attempting to create the graph sought. Bay State will update or supplement this response when the information is available.

COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF TELECOMMUNICATIONS AND ENERGY

RESPONSE OF BAY STATE GAS COMPANY TO THE
SECOND SET OF INFORMATION REQUESTS FROM THE ATTORNEY GENERAL
D. T. E. 05-27

Date: June 6, 2005

Responsible: Stephen H. Bryant, President

AG-2-48 Provide copies of all prefiled testimony, schedules, exhibits, responses to discovery and settlements related to the “two base rate increases” referenced in the testimony of Stephen H. Byrant, Exh. BSG/SHB-1, p. 9 of 58, lines15-18.

Response: This material, which is available to the Attorney General as it is in the public domain, is still being gathered and prepared for exhibit format. Bay State will supplement this response when the material has been compiled.

COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF TELECOMMUNICATIONS AND ENERGY

RESPONSE OF BAY STATE GAS COMPANY TO THE
SECOND SET OF INFORMATION REQUESTS FROM THE ATTORNEY GENERAL
D. T. E. 05-27

Date: June 6, 2005

Responsible: Stephen H. Bryant, President

AG-2-49 Provide copies of all the prefiled testimony, exhibits, responses to discovery and hearing transcripts concerning the Company's depreciation witness from the Company's rate case, D.T.E. 92-11 (1992).

Response: This material, which is available to the Attorney General as it is in the public domain, is still being gathered and prepared for exhibit format. Bay State will supplement this response when the material has been compiled.

COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF TELECOMMUNICATIONS AND ENERGY

RESPONSE OF BAY STATE GAS COMPANY TO THE
SECOND SET OF INFORMATION REQUESTS FROM THE ATTORNEY GENERAL
D. T. E. 05-27

Date: June 6, 2005

Responsible: Danny G. Cote, General Manager

AG-2-52 Has the Company ever conducted a cost / benefit or feasibility analysis to determine whether it would be prudent to retrofit the Company's existing bare steel mains and services with cathodic protection? Provide copies of all analyses, including any analysis of retrofitting with an impressed system of cathodic protection.

Response: Cathodic protection of bare steel mains and services is inappropriate for reasons of sound engineering and operations management.

As an initial matter, from an operational standpoint, it takes significantly more current to cathodically protect a bare steel pipe than it does to protect a coated steel pipe. Bay State has used cathodic protection broadly for its coated steel mains. See Bay State's response to AG-2-53. However, the ratio for current requirement of bare steel to coated steel is <u>one hundred to one</u> (100:1). While one single sacrificial anode will protect 400 feet of coated steel pipe, the same anode will protect only four (4) feet of bare steel. Unless some extremely unusual set of circumstances exist, the retrofit of a subsurface pipeline with sacrificial anodes every 4 feet will invariably be more expensive than simply opening a trench and replacing the pipe.

As suggested by the question, impressed current systems for bare steel produce very large amounts of current (in order to allay the inefficiencies described above), but still are only able to protect a limited amount of pipeline per rectifier. Since there is more current in the impressed current system, the overarching concern is damage to nearby third-party utility underground facilities due to stray current. Facility near impressed current that are not bonded in to the amperage producing rectifier (such as underground electric or telephone utilities) would suffer damage quickly.

In sum, based upon Bay State's managerial and operational expertise, the circumstances in which cathodic protection of bare steel facilities would be appropriate over simply replacing the pipe would be extremely rare and the result would be likely undesirable.

COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF TELECOMMUNICATIONS AND ENERGY

RESPONSE OF BAY STATE GAS COMPANY TO THE
SECOND SET OF INFORMATION REQUESTS FROM THE ATTORNEY GENERAL
D. T. E. 05-27

Date: June 6, 2005

Responsible: Danny G. Cote, General Manager

AG-2-53 Has the Company ever conducted a cost / benefit or feasibility analysis to determine whether it would be prudent to retrofit with cathodic protection the Company's existing coated steel mains and services with cathodic protection? Provide copies of all analyses, including any analysis of retrofitting with an impressed system of cathodic protection.

Response: Depending on what is known at any given time, consistent with high standards of utility management, Bay State has used the following criteria to determine when and if it is feasible to cathodically protect coated steel mains within its system. Each time it undertakes a feasibility analysis, that analysis constitutes a cost-benefit analysis for the use of cathodic protection in its system. The method of analyzing the feasibility for the use of cathodic protection will not change even though Bay State simultaneously is managing the SIR.

Bay State implemented cathodic protection on a broad scale in each of the three service areas of its distribution system from 1985 through 2003. In that time period, Bay State cathodically protected 193 miles of coated unprotected pipe in its Springfield Division; 36 miles of coated unprotected steel remain. Bay State cathodically protected 261 miles of coated unprotected pipe in its Brockton Division; 70 miles of coated unprotected steel remain. Bay State cathodically protected 6 miles of coated unprotected pipe in its Lawrence Division and currently has 3 miles left.

In sum, since 1985 Bay State brought 81 percent, or 460 miles, of all pre-1971 coated steel pipe under cathodic protection. Bay State's operations management, engineers and consultants agree that the remaining 19 percent, 109 miles, is made up of pipe segments that are not capable of being protected due to deteriorated condition; cannot be economically brought under cathodic protection because the materials consist of short segments scattered throughout the service territory; or are in locations where it is likely that the cathodic electrical current would cause damage to other subterranean utilities.

With regard to the feasibility, as part of Bay State's ongoing Corrosion Control monitoring, Bay State's underground distribution network has been and continues to be evaluated to determine when and where it is effective and practical to cathodically protect pre-1971 steel pipeline segments.

As a general matter, the decision to cathodically protect coated steel distribution pipe consisted and continues to consist of two steps.

First, Bay State identified all potential (coated but unprotected) pipe segments that could be protected. Annually, Bay State plots all corrosion leaks on a series of service area leak history maps. These maps serve as a visual aid to determine areas of potentially active corrosion. Bay State's Corrosion Department then examines this data, looking for segments of coated steel lines that were installed without cathodic protection, but are in areas where active corrosion appears to be present. Since Bay State installed post-1970 coated steel facilities with cathodic protection, the vulnerable segments are made up exclusively of pre-1971 vintage pipe.

Bay State operations managers, field leaders and system engineers also consider economic parameters in the replacement versus protection decision process. For example, if, in the reasonably near future it appears that pipe replacement will occur coincident with municipal work, as a result of pipe condition, or to increase system deliverability through increased capacity, Bay State would not undertake cathodic protection of the deteriorating segment. Interim repairs may be made until replacement is completed. There is no benefit to cathodically protecting a pipe that is in need of replacement.

In addition, Bay State must consider whether he pipe is an appropriate candidate for cathodic protection. The pipe's coating must be of sufficient quality to support cathodic protection. If the pipe coating has deteriorated because of age to the point where it indicates through tests essentially the same strength and resiliency as bare steel, it is not reasonable to undertake the measures to cathodically protect that segment when replacement is the appropriate remedial step.

Bay State's next step, after it has identified the potential distribution segments that are reasonable candidates for cathodic protection, is to analyze the feasibility of installing cathodic protection systems on these facilities. Public safety, operational issues and cost are among the considerations in determining whether cathodic protection is the appropriate action to take, or whether the coated steel pipe segment should be replaced in its entirety.

In Bay State's system design analysis, the type of soils present, the size and condition of both the pipe and its coating, and the sensitivity of the system location are paramount considerations. In additions, multiple other considerations come into play: a wetland disturbance, highway or rail crossing or a freshly paved street could well prevent the work required on the segment, or unreasonably increase the cost through permitting and conditions relative to the test stations required for actual pipe evaluation. After all of the analysis is completed, Bay State decides to protect or replace the affected segment.

If cathodic protection is deemed to an appropriate and effective strategy for segment longevity, Bay State must:

- Install test stations to access the pipe for the evaluation.
- The segments are then electrically isolated, which requires the installation of various types of insulating fittings.
- A cathodic protection system is designed and installed.

The last factor considered relates to the proximity of other underground utility facilities to the affected segment. Underground competition for utility space is often at a premium, especially in city streets. When the electrical current requirements are sufficient to cause interference with other utility services, Bay State will not install cathodic protection. Often, this issue is not even apparent until the ground is opened to examine the location of Bay State’s facilities in relation to others operated by third-party municipal or utilities. Damage may occur to adjacent natural gas transmission piping or to other utilities (telephone, electric) in congested business districts where Bay State shares its utility easement many other underground facilities. The electrical current necessary to provide cathodic protection can jump, arch or migrate. When our engineers indicate that their system design reflects adverse conditions from our use of cathodic protection relative to other underground utilities’ facilities, such as water, electric, cable or telephone, Bay State cannot install the system (even if other factors seem to indicate it may be favored).

COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF TELECOMMUNICATIONS AND ENERGY

RESPONSE OF BAY STATE GAS COMPANY TO THE
SECOND SET OF INFORMATION REQUESTS FROM THE ATTORNEY GENERAL
D. T. E. 05-27

Date: June 6, 2005

Responsible: Danny G. Cote, General Manager

AG-2-54 Has the Company created a system of prioritizing its corroded bare steel mains by segments in order to identify the worst sections of leaking pipe? If yes, please explain this system, including a complete description of factors used for prioritizing the leaking pipe. Include in this response all reports, analyses and employee manuals related to this system from 1995 to 2005.

Response: Bay State Gas Company does have a prioritization model for its bare steel mains in order to identify the worst performing segments of leaking pipe. It will use this same prioritization model, as well as other pertinent information (consistent with good utility practice), to prioritize the replacement of all unprotected steel under the SIR. The factors used in Bay State's current prioritization model for prioritizing the segments to be replaced provides the following operational details information:

1. Town (acts as asegment identifier);
2. Street (acts as asegment identifier);
3. Location (acts as asegment identifier (from – to))
4. Length (acts as asegment identifier)
5. Size (provides pertinent pipe characteristic)
6. Year Installed (provides pertinent pipe characteristic)
7. Operating Pressure (provides pertinent pipe characteristic)
8. Depth (provides pertinent pipe characteristic)
9. Pavement (provides pertinent pipe characteristic (wall to wall))
10. Public Buildings (provides pertinent pipe characteristic)

11. System Reinforcement Main (provides pertinent pipe characteristic)

12. System Improvement (provides pertinent pipe characteristic (may enhance system reliability and deliverability, meeting design criteria, to replace))

13. Condition (provides pertinent information relative to the condition of segment (as described during visual inspection and transcribed on the WOMS))

14. Leaks prior to 1992 (also provides pertinent information on thecondition of segment)

15. Leaks from 1993-2004 (also provides pertinent information on the condition of segment)

While last on this list, in reality, the factors pertaining to the condition of the segment are given the most weight in prioritizing. The visual indication of the condition of the pipe and its relative performance history will make up approximately 80% of the total weighting.

The factors pertaining to the pipe characteristics, while relevant, make up approximately 20% of the weighting.

Bay State's prioritization model is flexible in order to reflect Bay State's operating conditions and discovered events as they appear; it is therefore updated with relevant information as soon as practicable. In total, all the activities undertaken in leak surveying, system analysis, reliability, deliverability and work order management feed into the method used by Bay State operations management to prioritize system replacements.

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RESPONSE OF BAY STATE GAS COMPANY TO THE
SECOND SET OF INFORMATION REQUESTS FROM THE ATTORNEY GENERAL
D. T. E. 05-27

Date: June 6, 2005

Responsible: Danny G. Cote, General Manager

AG-2-55 Has the Company created a system of prioritizing its corroded coated steel without cathodic protected mains by segments in order to identify the worst sections of leaking pipe? If yes, please explain this system, including a complete description of factors used for prioritizing the leaking pipe. Include in this response all reports, analyses and employee manuals related to this system from 1995 to 2005.

Response: Please see Bay State's response to AG-2-54. Unprotected coated steel pipe is evaluated and prioritized in an identical manner to bare steel pipe. Consistent with reasonable utility and good system management practices designed to ensure safety, reliability and service in a least cost manner, all distribution mains replacements, whether bare steel, wrought iron, cast iron, or coated steel, are examined, evaluated, prioritized and replaced in the same deliberate manner.

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SECOND SET OF INFORMATION REQUESTS FROM THE ATTORNEY GENERAL
D. T. E. 05-27

Date: June 6, 2005

Responsible: Danny G. Cote, General Manager

AG-2-56 Does the Company's SIR program use the prioritizing system(s) described in response to AG-2-54 and AG-2-55 to evaluate and replace the worst Segments of pipe first in the Company's service territories? If no, then describe in detail the prioritizing system for leaking pipes used by the SIR program.

Response: Yes, Bay State's SIR program uses the "system," or method of analysis, updated with other evaluative information that it deems, based the on operational and management experience and judgment that comes from managing a natural gas distribution system, to be reasonable to use to evaluate the worst performing segments for initial geographic targeting for replacement.

Please note, as stated in previous responses, that Bay State's SIR program prioritizes unprotected steel replacement through the use of a combination of factors, with leak rates and pipe condition as primary drivers, consistent with the methods used to replace other non-performing parts of the distribution system unrelated to steel. While this list is not exhaustive, other factors that would considered with regard to the manner in which prioritization is undertaken in the SIR program are: the geographical proximity of a non-performing segment to other unprotected steel segments (that results in the best contractor pricing because the contractors look favorably on the ability to control mobilization costs) and Bay State's opportunity to coordinate the needed replacement with municipal or state highway construction.

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Date: June 6, 2005

Responsible: Danny G. Cote, General Manager

AG-2-57 Does the Company's Operations and Maintenance ("O&M") program used to repair or replace corroded mains use a prioritizing system in order to identify the worst sections of pipe? If yes, please explain this system, including a complete description of factors used for prioritizing the leaking pipe and scheduling its replacement. Include in this response all reports and analyses related to this system from 1995 to 2005, and identify by name the two Company employees most responsible for rescheduling repairs and replacements of mains for each of the years from 1995 to 2005.

Response: Bay State's O&M procedure 7.80 is followed to assess and report the condition of the pipe and pipe coating, when coating is present. Company employees note the overall condition of the exposed pipe, any coating damage, any graphitization, the pit depth on steel pipe and describe the type of corrosion damage (e.g. uniform, general, or localized corrosion) if any. O&M procedure 14.15 provides guidance in making a determination of whether the pipe will be repaired or replaced. If the distribution crew finds the main to be in good, fair or poor condition at the leak location, the crew installs a repair clamp on the main and notes the condition of the pipe and coating on the work order. If the main segment is made of steel, shows signs of deterioration or mechanical damage, then the Company employee(s) at the field location will note their findings on the work order and notify the Field Operations Leader ("FOL"), as appropriate. If the main segment is made of steel and is in very poor condition, the distribution crew will report their findings immediately to the FOL, Construction Specialist or Operations Manager or his designee for review within 24 hours. If the main is not replaced immediately, the aforementioned will notify Local Engineering to designate the segment as a candidate for replacement and prioritize the replacement according to a point system in their bare steel replacement database.

Please see AG-2-56 for Bay State's prioritization methodology.

The two employees most responsible for scheduling repairs and replacements in each division, each year from 1995 to 2005 are as follows:

Brockton Division:	
Mike Laghetto	1995-1998
Bill St. Cyr	1999-2005
Springfield Division	
Ted Dulchinos	1995-2001
Keith Dalton	2001-2002
Pam Bellino	2002-2005
Lawrence Division	
Vic Platania	1995-1998
Mike Laghetto	1999-2005

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Date: June 6, 2005

Responsible: Danny G. Cote, General Manager

AG-2-58 Will the Company continue to use its O&M program described in AG-2-57 after 2005?

Response: Yes. Bay State will continue to use the model in conjunction with the process described in its response to AG-2-56.

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Date: June 6, 2005

Responsible: Danny G. Cote, General Manager

AG-2-59 Compare and contrast in detail the Company's SIR program pipe prioritizing system with the pipe prioritizing system implemented by Northern Utilities in DR 91-081 (1992).

Response: The prioritization model is the same for both Bay State's SIR program pipe prioritizing system and the prioritizing system approved by the New Hampshire Public Utilities Commission in NHPUC Docket DR 91-081 and implemented by Bay State's affiliate, Northern Utilities, Inc. ("Northern"), for use to replace bare steel infrastructure in its New Hampshire Division. However, there is a difference in the scope of each program, which does lead to different applications of the prioritization model. By "prioritization model," Bay State means the method by which it selects the pipe segments in the replacement program that should be targeted for replacement.

As designed, the SIR program is a ten to fifteen year program designed to replace all of the unprotected steel in the distribution system in a geographical manner. Therefore, the prioritizing model in the SIR is used to determine the manner in which the geographic targeting will be commenced, i.e. the large sections of the distribution system that will be replaced based on groupings of the worst pipe segments (initially determined to be in the Brockton service area). The identification of large geographic areas of poorly performing unprotected steel will allow Bay State to coordinate its work with local municipalities and perform its replacements more efficiently without being required to stage, unassemble and relocate the replacement worksite from town to town on a daily basis.

By contrast, the Northern program implemented in DR 91-081 was a program to replace the worst bare steel pipe segments each year, over a ten-year period. By contrast to the instant proposal, Northern's program was not intended to replace 100% of the bare steel in Northern's New Hampshire Division distribution system, and the actual amount of bare steel to be replaced in any year was not prescribed. In that replacement project, the prioritization model was used to assess the deterioration of certain segments and to replace those segments first. It was expected that at the end of the first ten years, bare steel would remain a component material in Northern's distribution system infrastructure.

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Date: June 6, 2005

Responsible: Stephen H. Bryant, President
Danny G. Cote, General Manager

AG-2-60 Please provide all facts and documentary evidence to support the answer "Yes it has " to the question in the prefiled testimony "Has Bay State been responsible and prudent in its past maintenance and repair procedures for its steel facilities?" Testimony of Stephen H. Bryant, Exh.BSG/SHB-1, p. 37 of 58 lines 20-21, p. 38 of 58 line 1. In addition, list what type of Company property is included in the definition of "steel facilities" as used in the quoted question.

Response: Bay State is still compiling its response and will supplement when the response is prepared.

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Date: June 6, 2005

Responsible: Danny G. Cote, General Manager

AG-2-62 When did development of the SIR program start, and when was the program details finalized and adopted? Provide all reports, memorandums and analyses related to the decision to adopt the program.

Response: Bay State analyzes corrosion leakage in its system using the data filed annually in the DOT 7100 reports, and it has done so for many years.[1] The leakage trend line from 1985 to 2003 clearly shows that the rate of leakage continues to escalate, and the replacement methods traditionally used by Bay State, which are consistent with reasonable natural gas system management, is not sufficient to offset the increasing corrosion leakage rate that is occurring in Bay State's system.[2]

As a result of its analysis of the total 2003 leak rates and the established trend discussed above, Bay State authorized the expenditure of an additional $8,000,000 in order to undertake a broader steel infrastructure capital replacement program during 2004. Bay State also retained the services of RJ Rudden to review Bay State's historical DOT data and to examine Bay State's conclusions through an independent assessment of the performance of Bay State's unprotected steel system.[3] RJ Rudden affirmed that Bay State's unprotected steel was failing at an accelerated rate, and that the only reasonable recourse from a system reliability and maintenance perspective was to substantially accelerate the unprotected steel pipe replacement rate.

As a result of ongoing internal discussions and the RJ Rudden analysis, which confirmed Bay State's conclusions, Bay State decided in 2004 to proceed with the proposed 12-15 year Steel Infrastructure Replacement ("SIR") program, and to seek an appropriate method of rate recovery as

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[1] See the Company's response to AG 6-8 for copies of all DOT 7100 system reports submitted to the DOT since 1995.

[2] See the Company's response to DTE 3-6, which provides two graphs that illustrate these important trends.

[3] See the Company's response to AG-2-16 for a copy of the RJ Rudden Report.

part of its Annual Base Rate Adjustment Mechanism (“ABRAM”) to be proposed in its 2005 rate case filing.